FILED
03-03-08
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004) (QF Issues)
Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-Run and Long-Run Avoided Costs, Including Pricing for Qualifying Facilities.	Rulemaking 04-04-025 (Filed April 22, 2004) (QF Issues)

PETITION OF THE CALIFORNIA COGENERATION COUNCIL
FOR MODIFICATION OF DECISION 07-09-040

Jerry R. Bloom
Joseph M. Karp
Catherine L. Pollina
Winston & Strawn LLP
101 California Street, 39th Floor
San Francisco, California 94111-5894
Telephone: (415) 591-1000
Facsimile: (415) 591-1400
Email: jkarp@winston.com
Attorneys for the California Cogeneration Council

March 3, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004) (QF Issues)
Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-Run and Long-Run Avoided Costs, Including Pricing for Qualifying Facilities.	Rulemaking 04-04-025 (Filed April 22, 2004) (QF Issues)

PETITION OF THE CALIFORNIA COGENERATION COUNCIL FOR MODIFICATION OF DECISION 07-09-040

I. INTRODUCTION

Pursuant to Rule 16.4 of the California Public Utilities Commission's ("Commission's") Rules of Practice and Procedure, the California Cogeneration Council ("CCC") respectfully submits this Petition to Modify Decision 07-09-040 ("Decision"). The Decision adopts new pricing and contract options for the investor-owned utilities' ("IOUs'") purchase of energy and capacity from qualifying facilities ("QFs"). The CCC seeks an order modifying the Decision to (i) clarify that QFs whose firm capacity contracts expired prior to the date of the Decision may revert back to the non-price terms of their original firm capacity contracts and employ the newly adopted firm capacity price until the new QF contracts required in the Decision are implemented, just as QFs whose firm capacity contracts expire after the date of the Decision are entitled to do under the Decision; (ii) require that the combustion turbine ("CT") costs used in determining the price for as-available capacity and the Market Price Referent ("MPR") used as the basis for the firm capacity price be updated annually to reflect prevailing avoided costs; and (iii) clarify that the IOUs should implement the Market Index Formula ("MIF") methodology for short-run avoided cost ("SRAC") energy payments and the new as-available capacity prices adopted in the Decision simultaneously and on a prospective basis beginning with the first month following a Commission resolution implementing the IOUs' joint Tier 3 MIF advice letter.

II. DISCUSSION

A. Firm Capacity QFs Whose Contracts Have Expired Prior to the Decision Should be Allowed to Extend the Non-Price Terms of their Expired Contracts

As written, the Decision expressly allows QFs with expiring firm capacity contracts to reinstate the non-price terms of these contracts along with the new firm capacity price adopted in the Decision pending Commission adoption of the new QF contracts required to be implemented in the Decision.[1] However, the Decision neglects to state expressly that the same policy would apply to firm capacity QFs whose contracts expired prior to the issuance of the Decision and who have been on interim as-available contracts approved by the Commission in the meantime. The CCC urges the Commission to modify the Decision so that this policy clearly applies to firm capacity QFs with expired contracts in addition to those with expiring contracts.

Since 2002, the CCC, representing existing firm capacity QFs with expired and expiring contracts, has sought a long-term QF contracting policy from the Commission. While it worked on establishing the policy, the Commission provided a mechanism to allow these QFs to continue to sell power to the utilities in the interim: the Standard Offer 1 ("SO1") contract was reinstated for QFs with contracts that would expire in 2003.[2] Believing that finalization of the QF policy was imminent, the Commission continued to extend the interim relief on a year to year

[1] D. 07-09-040 at 126 (Sept. 25, 2007).
[2] D. 02-08-071 at 32 (Aug. 22, 2002).

basis in subsequent Decisions.[3] Finally, in 2005 the relief was extended "until the Commission issues a final decision in the combined two dockets, Rulemaking (R.) 04-04-003 and R.04-04-25."[4]

The SO1 contract option, the sole form of interim relief offered by the Commission, however, is an as-available capacity contract. It contains significantly lower capacity payments than the pre-existing firm capacity contracts or the new firm capacity contracts adopted in the Decision. It also contains no performance obligation for the QF, other than to sell all project output in excess of on-site or over-the-fence consumption to the IOU.

Without an alternative form of relief, QFs with expiring firm contracts were forced to accept the SO1 contracts offered by the IOUs during the interim and to receive the lower as-available capacity prices.[5] They did this even though, as a result of obligations to deliver thermal energy to their industrial or agricultural hosts, they actually provide the equivalent of firm capacity to the IOUs. As such, these QFs have been and are being significantly underpaid for their product. Although the Decision rectifies this for "existing firm capacity QF resources whose contracts expire before the contracts required by this decision are available"[6] the Decision has been interpreted such that QFs whose contracts have already expired are again left without a viable option for relief other than to remain on the SO1 contracts until the new firm capacity contract is implemented.

Stated simply, there is no rational basis to distinguish on this issue between firm capacity QFs whose contracts expired before September 25, 2007 (when the Decision was issued) and firm capacity QFs whose contracts expire after September 25, 2007. Indeed, in light of the years

[3] D. 03-12-062 at 92 (Dec. 18, 2003) and D. 04-01-050 at 198 (Jan. 22, 2004).
[4] D. 05-12-009 at 1 (Dec. 1, 2005).
[5] Kern River Cogeneration Company, which spent years negotiating a five-year contract with Southern California Edison Company, appears to be an exception.
[6] D. 07-09-040 at 126; 148 (Finding of Fact 46).

of receiving as-available SO1 capacity prices for firm capacity, QFs whose firm capacity contracts expired before the Decision are at least as deserving (and possibly more so) of the relief provided in the Decision than those whose contracts expire between the date of the Decision and the implementation of the new contracts.

Although the CCC does not know the exact number of QFs whose firm capacity contracts expired before the date of the Decision, we expect that a relatively small number of QFs would qualify. There are five such QFs within the CCC.

Accordingly, the CCC requests that the Decision be modified to expressly permit those QFs whose contracts expired prior to the issuance of the Decision and that entered into interim as-available contracts with the IOUs to reinstate the non-price terms of their expired firm capacity contracts along with the new pricing contained in the Decision. This can be done by making the following three changes to the Decision:

1. By revising the text of the second sentence on page 126 of the Decision to refer to "existing firm capacity QF resources (1) whose contracts expired before the date of this decision and that entered into interim SO1 contracts or their equivalent under our prior orders or (2) whose contracts expire before the contracts required by this decision are available".

2. By revising the text "expiring contract" in the third sentence on page 126 of the Decision to read "expiring or expired firm capacity contract".

3. By revising the text "expiring contracts" in Finding of Fact 46 to read "expiring or expired firm capacity contract".

B. Prices for As-Available Capacity and Firm Capacity Should Be Updated Annually

The Decision adopts revised CT cost assumptions for use in setting as-available capacity payments to QFs.[7] The Decision also adopts a new cost basis for setting firm capacity QF payments, the MPR.[8] Unfortunately, the Decision fails to provide for the inevitable fact that CT costs and the MPR (and the underlying costs that make up the MPR) will change with time, and are regularly updated by the Commission to incorporate such changes.[9] The need to update QF capacity prices is particularly acute given the sharp increases over the past several years in the costs to build new generating capacity in California and the U.S.[10] Due to the protracted litigation that resulted in the Decision, the record in this proceeding was developed in 2004 – 2005, before the spike in power plant construction costs.

As discussed below, the CCC proposes that the Decision be modified to require that the prices for as-available and firm capacity be updated annually so that these prices keep pace with prevailing costs. This is not a new concept; as-available capacity costs used to be updated annually in ECAC proceedings. Failing to update QF payments to reflect prevailing capacity costs would violate PURPA's avoided cost requirement.[11]

To be clear, although firm capacity prices should be updated, the updated prices should only be used prospectively, in newly executed contracts; as has always been done, once a firm capacity contract is signed, the capacity price should be locked in for the contract term. Unlike

---

[7] *Id.* at 8.
[8] *Id.*
[9] In fact, the Decision expressly states that it will not update "the starting point" for firm capacity prices adopted in the Decision. *See* D. 07-09-040 at 98 (footnote 100).
[10] Attachment A to this petition includes a recent study from the Brattle Group, performed for the Edison Foundation, documenting these increases, as well as a recent article on a similar study from Cambridge Energy Research Associates.
[11] The CCC has challenged the Decision's adopted CT costs in an application for rehearing as being out of date, and does not in any way compromise such challenge through this petition to modify.

firm capacity prices, as-available capacity prices should "float" with the prevailing as-available price methodology (on a prospective basis within a given contract), including any updated CT costs; this has always been the Commission's practice with respect to as-available capacity prices under SO1 contracts.

The need to update CT costs for the as-available capacity prices is plainly apparent.[12] The as-delivered capacity price adopted in the Decision is based on The Utility Reform Network's ("TURN's") calculation using an installed CT cost of $523 per kW in 2004, escalated in subsequent years at 2.5% per year, resulting in an estimate of installed CT costs in 2007 of $563 per KW.[13] This value, however, is just 39% of what Southern California Edison Company ("SCE"), for example, spent on its four new CT peakers in 2007.[14] Another recent data point is the 2007 CT cost of $1,053 per kW reported by the California Energy Commission ("CEC") in its December 2007 report on the comparative costs of new electric generation in California.[15] The CT value adopted in the Decision is just 53% of this more up-to-date CEC estimate. The CCC believes that the Commission would be justified using SCE's recent CT costs of $1,456 per kW as the basis for a revised as-available capacity price – after all, these are SCE's actual costs for new CTs. However, to be conservative and because this is a statewide value, the CCC proposes to use the average of the SCE and CEC CT capital costs, or $1,255 per kW.

The as-available capacity price adopted in the Decision is the annualized fixed cost of a new CT (using a real economic carrying charge method), less the energy and ancillary service

---

[12] Although the methodology adopted in the Decision provides for 2.5% escalation, that only brings 2004 CT costs to 2007 dollars; this is not the same as using up-to-date 2007 CT costs for 2008 contracts.
[13] D. 07-09-040 at 96, adopting TURN's calculation from Ex. 149 (TURN/Marcus), Appendix B, Tables B-1 and B-2.
[14] The final completion cost of these units will be $262 million for 180 MW of capacity, or $1,456 per kW. See SCE's application for cost recovery for these units, A. 07-12-029, at 2-3.
[15] CEC, "Comparative Costs of California Central Station Electricity Generation Technologies," at 32, Table 19. This CEC report is available at http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

revenues earned by a CT. The CCC anticipates that the utilities will argue that, if the capital cost of a CT is updated, the assumptions for the energy rent and ancillary service revenues earned by a CT also should be updated. The CCC agrees, and proposes to use the four-year (2003 – 2006) average of the California Independent System Operator's ("CAISO's") calculation of the energy rent and ancillary service revenues earned by a new CT, as published in the CAISO's *2006 Annual Report on Market Issues and Performance (2006 Annual Report)*, which is the most recent available.[16] Energy rents and ancillary service prices fluctuate from year-to-year depending on market conditions, and thus the CCC recommends the use of a multi-year average, which is also how the CAISO presents the results of its analysis. The updated CT energy rents and ancillary service revenues are $48.65 per kW-year,[17] compared to the $31.60 per kW-year used in the Decision. The new as-available capacity price, as determined by the CCC using the methodology approved in the Decision, is $91.14 per kW-year.[18] The CCC proposes that the Commission adopt this value for implementation immediately.

Significant cost increases also have been observed for combined-cycle gas turbine ("CCGT") plants, the basis for the MPR used to set the firm capacity price in the Decision. Indeed, the CCGT capital costs included in the recently adopted 2007 MPR[19] are eight percent (8%) higher than the capital costs included in the 2006 MPR[20] on which the Decision's firm capacity price is based. The annualized CCGT fixed costs from the 2006 MPR model used as

---

[16] This CAISO report is available at http://www.caiso.com/1b7e/1b7e71dc36130.html. Section 2.6 of this report discusses the CAISO's annual analysis of the net revenues earned by new generation in California, and is included as Attachment B for the Commission's convenience. We note that the CAISO assumes that the dispatcher of the new generation has perfect fore-knowledge of day-ahead and real-time prices; thus, the CAISO concedes that its estimates of the revenues earned by new generation "may be considered the upper limits of potential revenues" (page 2.55).

[17] CAISO *2006 Annual Report*, at 2.55, Table 2.12. The CCC uses a 50/50 average of the net CT energy and ancillary service revenues for NP-15 and SP-15.

[18] *See* Attachment C for the supporting calculations, which follow the TURN real economic carrying charge method adopted in the Decision.

[19] Resolution E-4118 (Oct. 4, 2007), Appendix D, Row 1, showing a CCGT capital cost of $1,054 per kW.

[20] Resolution E-4049 (Dec. 14, 2006), Appendix E, Row 1, showing a CCGT capital cost of $980 per kW.

the basis for the firm capacity price in the Decision are $156.97 per kW-year (the MPR for a ten-year contract starting in 2007).[21] The comparable value for 2008 (the MPR for a ten-year contract starting in 2008) using the adopted 2007 MPR model is $181.12 per kW-year,[22] a 15.4% increase over the firm capacity price adopted in the Decision.

The CCC notes that, similar to the as-available capacity price, the Decision adopted a firm capacity price based on the annualized CCGT fixed costs, from the MPR, less the energy rents earned by a new CCGT and a $10 per kW-year deduction to reflect the fact that a CCGT has a longer life than 20 years.[23] The Decision's energy rent estimate ($55 per kW-year) was taken from the CAISO's *2004 Annual Report*, and the CCC expects that the utilities will argue that this element of the firm capacity price also should be updated. The CCC agrees, and proposes to use the four-year (2003 – 2006) energy rent value of $62.20 per kW-year published in the CAISO's *2006 Annual Report* (which is also the source for the CT's energy rent and ancillary service revenues discussed above).[24] As with the as-available calculation, the CCC recommends the use of the CAISO's multi-year average because energy rents vary from year-to-year with market conditions. The new firm capacity price, as determined by the CCC, is $108.92 per kW-year.[25] The CCC proposes that the Commission adopt this value for immediate implementation.

After the initial update to the firm capacity price proposed herein, updating the firm capacity price should be a relatively easy task; whenever a new MPR is adopted by the Commission (which will presumably happen each year in conjunction with the annual RPS

---

[21] D. 07-09-040 at 97-99.

[22] Resolution E-4118 (October 4, 2007); see the adopted MPR model, Tab "Cap_Fac", Cell E4, for a ten-year contract starting in 2008.

[23] D. 07-09-040 at 98-99.

[24] CAISO *2006 Annual Report*, at 2.55, Table 2.11. The CCC uses a 50/50 average of the CCGT net energy revenues for NP-15 and SP-15. No ancillary service revenues are included.

[25] *See* Attachment D for the supporting calculations.

solicitations), the utilities should be required to file a joint Tier 3 advice letter to update the firm capacity price using the same methodology adopted in the Decision, but with the new MPR values.

After the initial as-available capacity price update proposed herein, future updates of as-available capacity prices should also be done by Tier 3 advice letter. The IOUs should be required to make a joint filing using the most recent publicly available information on CT costs, including, obviously, any data associated with their own CTs. The filing should be made by September 30 of each year, with a target implementation date of January 1 of the following year.

C. The New SRAC Energy Price Formula and As-Available Capacity Prices Should Become Effective Prospectively For The First Month Following the Commission's Approval of the IOUs' Joint Tier 3 Advice Letter Implementing the MIF

Since the Decision was issued there has been some confusion as to when the revised SRAC energy pricing formula (i.e., the MIF) and new as-available capacity price would start to be employed in existing and new contracts. For example, in its reply to protests of Advice 2193-E, the joint advice letter implementing the MIF, SCE proposed that the Commission implement the MIF retroactively to the effective date of the Decision.[26] It has also proposed to pay QFs signing new QF contracts using the methodology contained in Advice 2193-E, even before the Commission has acted on this proposal. At the workshop conducted by the Energy Division, however, the IOUs were asked when they anticipated first implementing the MIF, and as the notes circulated by the Energy Division after the workshop reflected, each proposed to implement the MIF prospectively upon the approval of the joint Tier 3 MIF advice letter[27]

[26] SCE letter "Re: Market Index Formula Implementation (R.04-04-003/R.04-04-025)", addressed to Elizabeth Stoltzfus at the Commission, dated Feb. 25, 2008.
[27] Elizabeth Stoltzfus' Notes from the Qualifying Facility Program Implementation Workshop, held by the Commission's Energy Division on Nov. 14-15, 2007 (*see* Day 2, Extension of Expiring Contracts: "Agreement: MIF effective on the first calendar day of the month following 30 days after resolution goes into effect").

(although SCE reserved the right to seek a retroactive application of the MIF in accordance with its pending application for rehearing of the Decision – which application seeks retroactivity to 2004[28] and is not premised upon the effective date of the Decision as any meaningful point of departure).

Obviously, the CCC is strongly opposed to any retroactive application of the MIF, as such retroactivity would seriously disrupt prior commercial decisions made by QFs. Moreover, there is no basis for implementing the MIF until the methodology has been adopted by the Commission. As directed in the Decision, the IOUs were to file Tier 3 advice letter filings to implement the MIF; nothing in the Decision allows them to retroactively apply the methodology or to apply an un-approved version of the methodology pending its adoption.

Regarding confusion over when to start implementing new as-available capacity price, Pacific Gas & Electric Company's ("PG&E's") avoided cost posting for January 2008 reflects the new as-available capacity value adopted in the Decision.[29] In contrast, SCE and San Diego Gas & Electric Company ("SDG&E"), in their January 2008 avoided cost postings simply continue to use the as-available capacity values in effect before the Decision.

Not surprisingly, PG&E chooses an early implementation date given that the as-available capacity value to be paid under its QF contracts will drop significantly (from $69.93 per kW-year, adjusted for inflation, in 2007 to the $35.87 adopted in the Decision). SCE chooses not to implement the new as-available capacity value since the *value* to be paid under its as-available QF contracts will increase significantly (from $4.93 per kW-year currently to the $35.87 adopted in the Decision).

---

[28] Application of PG&E, SCE, SDG&E, TURN, and the Division of Ratepayer Advocates for Rehearing of Decision 07-09-040 at 16 (filed Oct. 25, 2007).
[29] http://www.pge.com/suppliers_purchasing/qualifying_facilities/prices/index.html

The CCC admits that the Decision is not entirely clear as to when the IOUs should first implement the new as-available capacity value. However, one thing is certain: the IOUs cannot be allowed to choose different starting dates so as to adversely impact their particular QFs. Although CCC members are in both PG&E's and SCE's service territories and thus fall on both sides of this issue (some preferring later implementation and others preferring sooner implementation), the only fair approach to implementation of the newly-adopted value is a consistent approach. To achieve such consistency among the three IOUs, the CCC proposes that the new as-available capacity value for all three IOUs should become effective upon the Commission's approval of the IOUs' joint Tier 3 advice letters implementing the rest of the pricing changes adopted in the Decision. This approach has the merit of being prospective and of applying the pricing changes adopted in the Decision comprehensively as opposed to piecemeal.

III. CONCLUSION

For the foregoing reasons, the CCC respectfully requests that the Commission modify Decision 07-09-040 to (i) provide clear language permitting firm QFs whose contracts have expired prior to the Decision to extend the non-price terms of their expired contracts along with the new firm capacity price adopted in the Decision; (ii) require that the prices for as-available capacity and firm capacity be updated annually; and (iii) require that the newly-adopted MIF and as-available capacity value become effective prospectively with the first month following the Commission's adoption of a resolution on the IOUs' joint Tier 3 MIF advice letter.

Respectfully submitted,

____

Jerry R. Bloom
Joseph M. Karp
Catherine L. Pollina
Winston & Strawn LLP
101 California Street, 39th Floor
San Francisco, California 94111-5894
Telephone: (415) 591-1000
Facsimile: (415) 591-1400
Email: jkarp@winston.com
Attorneys for the California Cogeneration Council

Attachment A

Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
Gregory Basheda

The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people.

The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

The Brattle Group

The Brattle Group provides consulting services and expert testimony in economics, finance, and regulation to corporations, law firms, and public agencies worldwide. Our principals are internationally recognized experts, and we have strong partnerships with leading academics and highly credentialed industry specialists around the world.

The Brattle Group has offices in Cambridge, Massachusetts; San Francisco; Washington, D.C.; Brussels; and London.

Detailed information about *The Brattle Group* is available at www.brattle.com.

Published by:
The Edison Foundation
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-347-5878

Table of Contents

Introduction and Executive Summary

In *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), *The Brattle Group* identified fuel and purchased-power cost increases as the primary driver of the electricity rate increases that consumers currently are facing. That report also noted that utilities are once again entering an infrastructure expansion phase, with significant investments in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and new environmental controls. The report concluded that the industry could make the needed investments cost-effectively under a generally supportive rate environment.

The rate increase pressures arising from elevated fuel and purchased power prices continue. However, another major cost driver that was not explored in the previous work also will impact electric rates, namely, the substantial increases in the costs of building utility infrastructure projects. Some of the factors underlying these construction cost trends are straightforward—such as sharp increases in materials cost—while others are complex, and sometimes less transparent in their impact. Moreover, the recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to the "sticker shock" that utilities experience when obtaining cost estimates or bids and that state public utility commissions experience during the process of reviewing applications for approvals to proceed with construction. While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators.

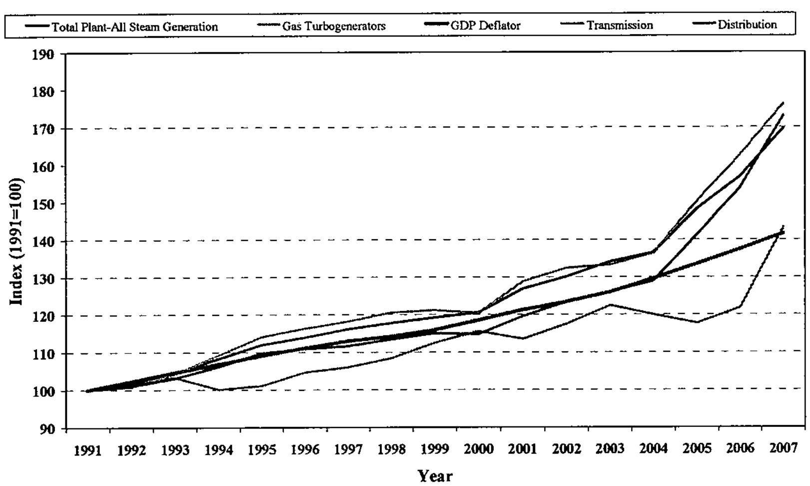
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment. This report also provides a reference for utilities, regulators and the public to understand the issues related to recent construction cost increases. In summary, we find the following:

- Dramatically increased raw materials prices (*e.g.*, steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.
- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or projected supply. There also is a growing backlog of

project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects. Large proposed transmission projects have undergone cost revisions, and distribution system equipment costs have been rising rapidly. This is seen in Figure ES-1, which shows recent price trends in generation, transmission and distribution infrastructure costs based on the Handy-Whitman Index© data series, compared with the general price level as measured by the gross domestic product (GDP) deflator over the same time period.[1] As shown in Figure ES-1, infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more—substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants—and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

Figure ES-1
National Average Utility Infrastructure Cost Indices

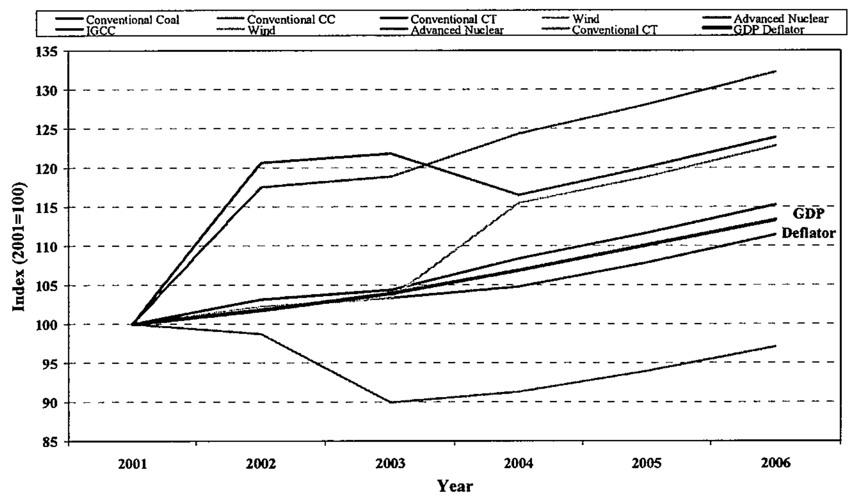


Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

[1] The GDP deflator measures the cost of goods and services purchased by households, industry and government, and as such is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives in order to reduce the future rate impacts on consumers.
- Despite the overwhelming evidence that construction costs have risen and will be elevated for some time, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA's) 2007 *Annual Energy Outlook* (AEO). The AEO generation capital cost assumptions since 2001 are shown in Figure ES-2. Since 2004, capital costs of all technologies are assumed to grow at the general price level—a pattern that contradicts the market evidence presented in this report. The growing divergence between the AEO data assumptions and recent cost escalation is now so substantial that the AEO data need to be adjusted to reflect recent cost increases to provide reliable indicators of current or future capital costs.

Figure ES-2
EIA Generation Construction Cost Estimates



Sources: Data collected from the U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

Projected Investment Needs and Recent Infrastructure Cost Increases

Current and Projected U.S. Investment in Electricity Infrastructure

The electric power industry is a very capital-intensive industry. The total value of generation, transmission and distribution infrastructure for regulated electric utilities is roughly $440 billion (property in service, net of accumulated depreciation and amortization), and capital expenditures are expected to exceed $70 billion in 2007.[2] Although the industry as a whole is always investing in capital, the rate of capital expenditures was relatively stable during the 1990s and began to rise near the turn of the century. As shown in *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon: According to the *World Energy Investment Outlook 2006*, investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030.[3]

Generation

As of December 31, 2005, there were 988 gigawatts (GW) of electric generating capacity in service in the U.S., with the majority of this capacity owned by electric utilities. Close to 400 GW of this total, or 39 percent, consists of natural gas-fired capacity, with coal-based capacity comprising 32 percent, or slightly more than 300 GW, of the U.S. electric generation fleet. Nuclear and hydroelectric plants comprise approximately 10 percent of the electric generation fleet. Approximately 49 percent of energy production is provided by coal plants, with 19 percent provided by nuclear plants. Natural gas-fired plants, which tend to operate as intermediate or peaking plants, also provided about 19 percent of U.S. energy production in 2006.

The need for installed generating capacity is highly correlated with load growth and projected growth in peak demand. According to EIA's most recent projections, U.S. electricity sales are expected to grow at an annual rate of about 1.4 percent through 2030. According to the North American Electric Reliability Corporation (NERC), U.S. non-coincident peak demand is expected to grow by 19 percent (141 GW) from 2006 to 2015. According to EIA, utilities will need to build 258 GW of new generating capacity by 2030 to meet the

---

[2] Net property in service figure as of December 31, 2006, derived from Federal Energy Regulatory Commission (FERC) Form 1 data compiled by the Edison Electric Institute (EEI). Gross property is roughly $730 billion, with about $290 billion already depreciated and/or amortized. Annual capital expenditure estimate is derived from a sample of 10K reports surveyed by EEI.

[3] Richard Stavros. "Power Plant Development: Raising the Stakes." *Public Utilities Fortnightly*, May 2007, pp. 36-42.

projected growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-based capacity, that is more capital intensive than natural gas-fired capacity which dominated new capacity additions over the last 15 years, will account for about 54 percent of total capacity additions from 2006 to 2030. Natural gas-fired plants comprise 36 percent of the projected capacity additions in *AEO 2007*. EIA projects that the remaining 10 percent of capacity additions will be provided by renewable generators (6 percent) and nuclear power plants (4 percent). Renewable generators and nuclear power plants, similar to coal-based plants, are capital-intensive technologies with relatively high construction costs but low operating costs.

High-Voltage Transmission

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high voltage (230 kV and higher) transmission lines that ultimately serve more than 300 million customers. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers. Today, 134 control areas or balancing authorities manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since the beginning of 2000, the industry has invested more than $37.8 billion in the nation's transmission system. In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid, while the Edison Electric Institute (EEI) estimates that utility transmission investments will increase to $8.0 billion during 2007. A recent EEI survey shows that its members plan to invest $31.5 billion in the transmission system from 2006 to 2009, a nearly 60-percent increase over the amount invested from 2002 to 2005. These increased investments in transmission are prompted in part by the larger scale of base load generation additions that will occur farther from load centers, creating a need for larger and more costly transmission projects than those built over the past 20 years. In addition, new government policies and industry structures will contribute to greater transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

NERC projects that 12,873 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America over the 2006 to 2015 period. NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the PJM Interconnection LLC, such as the major new lines proposed by American Electric Power, Allegheny Power, and Pepco.

Distribution

While transmission systems move bulk power across wide areas, distribution systems deliver lower-voltage power to retail customers. The distribution system includes poles, as well as metering, billing, and other related infrastructure and software associated with retail sales and customer care functions. Continual investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to customers.

Continued customer load growth will require continued expansion in distribution system capacity. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over the investment levels incurred in 2004. EEI projects that distribution investment during 2007 will again exceed $17.0 billion. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of the increased dollar investment reflects the increased input costs of materials and labor to meet current distribution infrastructure needs.

Construction Costs for Recently Completed Generation

The majority of recently constructed plants have been either natural gas-fired or wind power plants. Both have displayed increasing real costs for several years. Since the 1990s, most of the new generating capacity built in the U.S. has been natural gas-fired capacity, either natural gas-fired combined-cycle units or natural gas-fired combustion turbines. Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years.

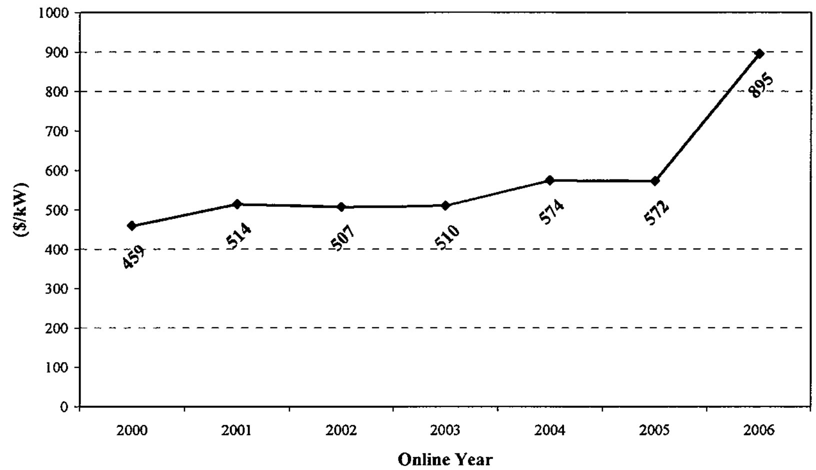
Using commercially available databases and other sources, such as financial reports, press releases and government documents, *The Brattle Group* collected data on the installation cost of natural gas-fired combined-cycle generating plants built in the U.S. during the last major construction cycle, defined as generating plants brought into service between 2000 and 2006. We estimated that the average real construction cost of all natural gas-fired combined-cycle units brought online between 2000 and 2006 was approximately $550/kilowatt (kW) (in 2006 dollars), with a range of costs between $400/kW to approximately $1,000/kW. Statistical analysis confirmed that real installation cost was influenced by plant size, the turbine technology, the NERC region in which the plant was located, and the commercial online date. Notably, we found a positive and statistically significant relationship between a plant's construction cost and its online date, meaning that, everything else equal, the later a plant was brought online, the higher its real installation cost.[4] Figure 1 shows the average yearly installation cost, in *nominal* dollars, as predicted by the regression analysis.[5] This figure shows that the average installation cost of combined-cycle units increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant construction costs.

---

4 To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

5 The nominal form regression results are discussed here to facilitate comparison with the GDP deflator measure used to compare other price trends in other figures in this report.

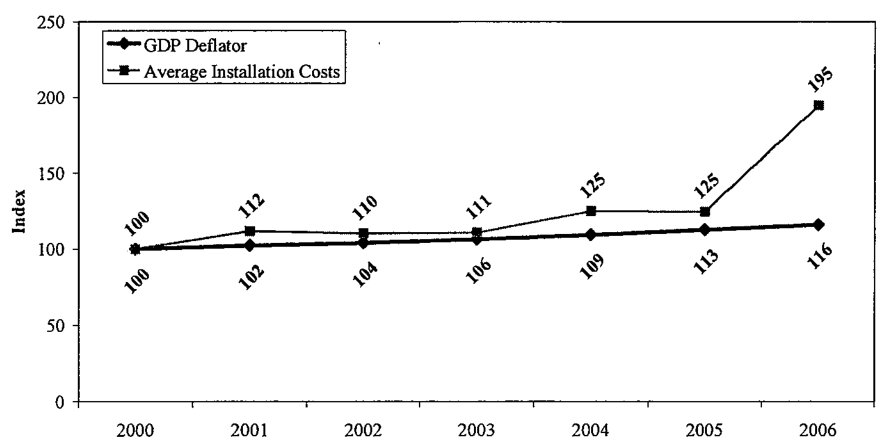
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.

Figure 2 compares the trend in plant installation costs to the GDP deflator, using 2000 as the base year. Over the period of 2000 to 2006, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

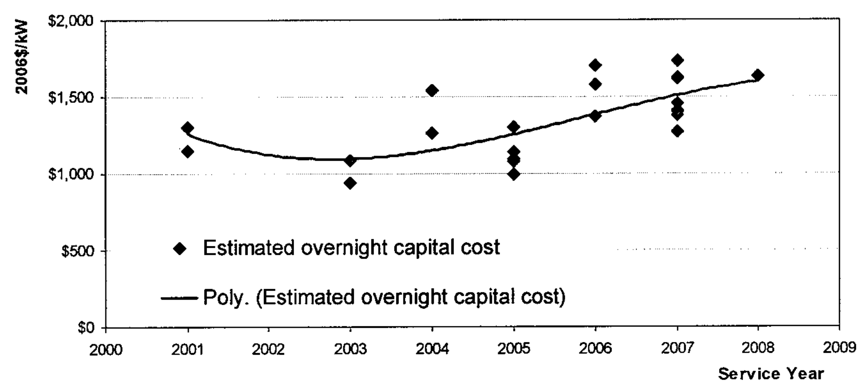
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.
** GDP Deflator data were collected from the U.S. Bureau of Economic Analysis.

Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, issued its most recent review of the cost of wind power in July 2006.[6] The Council found that the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than that assumed in its most recent resource plan. Specifically, the Council found that the levelized lifecycle cost of power for new wind projects rose 50 to 70 percent, with higher construction costs being the principal contributor to this increased cost. According to the Council, the construction cost of wind projects, in real dollars, has increased from about $1150/kW to $1300-$1700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. Factors contributing to the increase in wind power costs include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards established by a growing number of states. The Council notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel and resin have experienced significant cost increases in recent years. Figure 3 shows real construction costs of wind projects by actual or projected in-service date.

Figure 3
Wind Power Project Capital Costs



Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

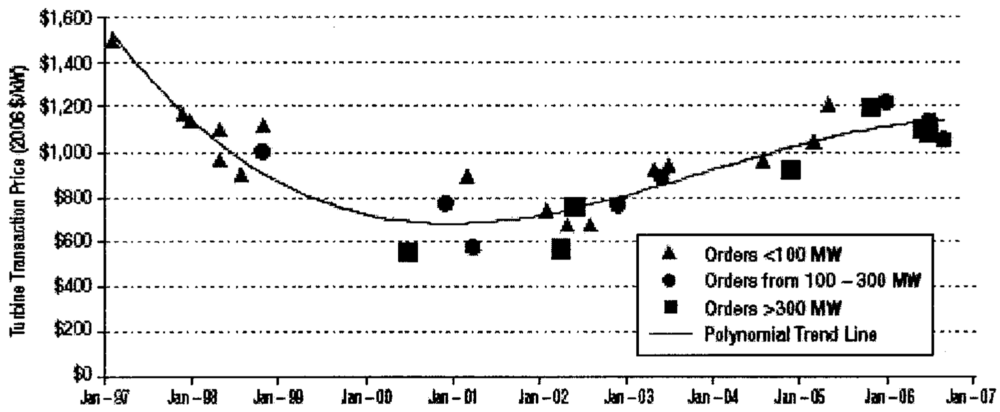
These observations were confirmed recently in a May 2007 report by the U.S. Department of Energy (DOE), which found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/kW between 2002 and 2006, a nearly 60-percent increase.[7] Figure 4 is reproduced from the DOE report (Figure 21) and shows the significant upward trend in turbine prices since 2001.

---

[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See "Biennial Review of the Cost of Windpower" July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower cost increases.

[7] See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006* Figure 21, page 16.

Figure 4
Wind Turbine Prices 1997 - 2007



Source: Berkeley Lab database.

Rising Projected Construction Costs: Examples and Case Studies

Although recently completed gas-fired and wind-powered capacity has shown steady real cost increases in recent years, the most dramatic cost escalation figures arise from *proposed* utility investments, which fully reflect the recent, sharply rising prices of various components of construction and installation costs. The most visible of these are generation proposals, although several transmission proposals also have undergone substantial upward cost revisions. Distribution-level investments are smaller and less discrete ("lumpy") and thus are not subject to similar ongoing public scrutiny on a project-by-project basis.

Coal-Based Power Plants

Evidence of the significant increase in the construction cost of coal-based power plants can be found in recent applications filed by utilities, such as Duke Energy and Otter Tail Power Company, seeking regulatory approval to build such plants. Otter Tail Power Company leads a consortium of seven Midwestern utilities that are seeking to build a 630-MW coal-based generating unit (Big Stone II) on the site of the existing Big Stone Plant near Milbank, South Dakota. In addition, the developers of Big Stone II seek to build a new high-voltage transmission line to deliver power from Big Stone II and from other sources, including possibly wind and other renewable forms of energy. Initial cost estimates for the power plant were about $1 billion, with an additional $200 million for the transmission line project. However, these cost estimates increased dramatically, largely due to higher costs for construction materials and labor.[8] Based on the most recent design refinements, the project, including transmission, is expected to cost $1.6 billion.

[8] Other factors contributing to the cost increase include design changes made by project participants to increase output and improve the unit's efficiency. For example, the voltage of the proposed transmission line was increased from 230 kV to 345 kV to accommodate more generation.

In June 2006, Duke submitted a filing with the North Carolina Utilities Commission (NCUC) seeking a certificate of public convenience and necessity for the construction of two 800 MW coal-based generating units at the site of the existing Cliffside Steam Station. In its initial application, Duke relied on a May 2005 preliminary cost estimate showing that the two units would cost approximately $2 billion to build. Five months later, Duke submitted a second filing with a significantly revised cost estimate. In its second filing, Duke estimated that the two units would cost approximately $3 billion to build, a 50 percent cost increase. The North Carolina Utilities Commission approved the construction of one 800 MW unit at Cliffside but disapproved the other unit, primarily on the basis that Duke had not made a showing that it needed the capacity to serve projected native load demands. Duke's latest projected cost for building one 800 MW unit at Cliffside is approximately $1.8 billion, or about $2,250/kW. When financing costs, or allowance for funds used during construction (AFUDC), are included, the total cost is estimated to be $2.4 billion (or about $3,000/kW).

Rising construction costs have also led utilities to reconsider expansion plans prior to regulatory actions. In December 2006, Westar Energy announced that it was deferring the consideration of a new 600 MW coal-based generation facility due to significant increases in the estimated construction costs, which increased from $1.0 billion to about $1.4 billion since the plant was first announced in May 2005.

Increased construction costs are also affecting proposed demonstration projects. For example, DOE announced earlier this year that the projected cost for one of its most prominent clean coal demonstration project, FutureGen, had nearly doubled.[9] FutureGen is a clean coal demonstration project being pursued by a public-private partnership involving DOE and an alliance of industrial coal producers and electric utilities. FutureGen is an experimental advanced Integrated Gasification Combined Cycle (IGCC) coal plant project that will aim for near zero emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, particulates and carbon dioxide (CO_2). Its initial cost was estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced that the project's price had increased to $1.7 billion.

Transmission Projects

NSTAR, the electric distribution company that serves the Boston metropolitan area, recently built two 345 kV lines from a switching station in Stoughton, Massachusetts, to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million. NSTAR stated that the increase is driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated. NSTAR further explained that there have been dramatic increases in material costs, with copper costs increasing by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

---

[9] U.S. Department of Energy, April 10, 2007, press release available at http://www.fossil.energy.gov/news/techlines/2007/07019-DOE_Signs_FutureGen_Agreement.html

Another aspect of transmission projects is land requirements, and in many areas of the country land prices have increased substantially in the past few years. In March 2007, the California Public Utilities Commission (CPUC) approved construction of the Southern California Edison (SCE) Company's proposed 25.6-mile, 500 kV transmission line between SCE's existing Antelope and Pardee Substations. SCE initially estimated a cost of $80.3 million for the Antelope-Pardee 500 kV line. However, the company subsequently revised its estimate by updating the anticipated cost of acquiring a right-of-way, reflecting a rise in California's real estate prices. The increased land acquisition costs increased the total estimate for the project to $92.5 million, increasing the estimated costs to more than $3.5 million per mile.

Distribution Equipment

Although most individual distribution projects are small relative to the more visible and public generation and transmission projects, costs have been rising in this sector as well. This is most readily seen in Handy-Whitman Index© price series relating to distribution equipment and components. Several important categories of distribution equipment have experienced sharp price increases over the past three years. For example, the prices of line transformers and pad transformers have increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[10] The cost of overhead conductors and devices increased over the past three years by 34 percent, and the cost of station equipment rose by 38 percent. These are in contrast to the overall price increases (measured by the GDP deflator) of roughly 8 percent over the past three years.

[10] Handy-Whitman© Bulletin No. 165, average increase of six U.S. regions. Used with permission.

Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

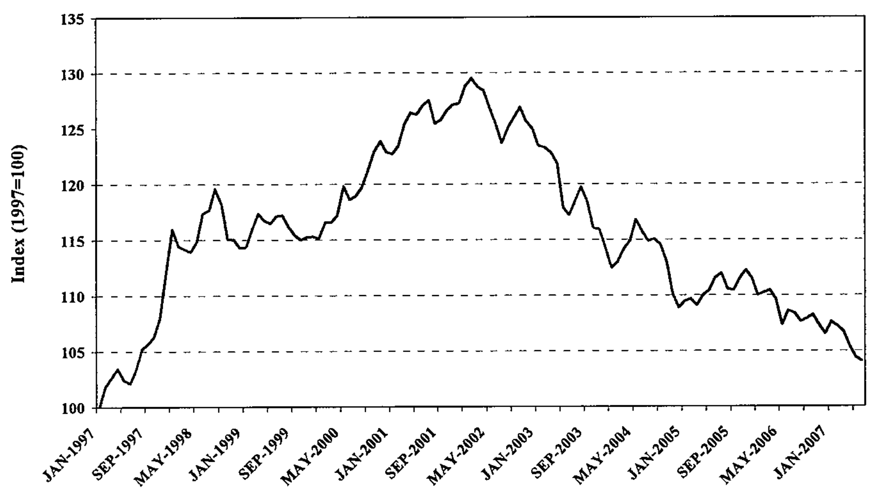
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

Exchange Rates

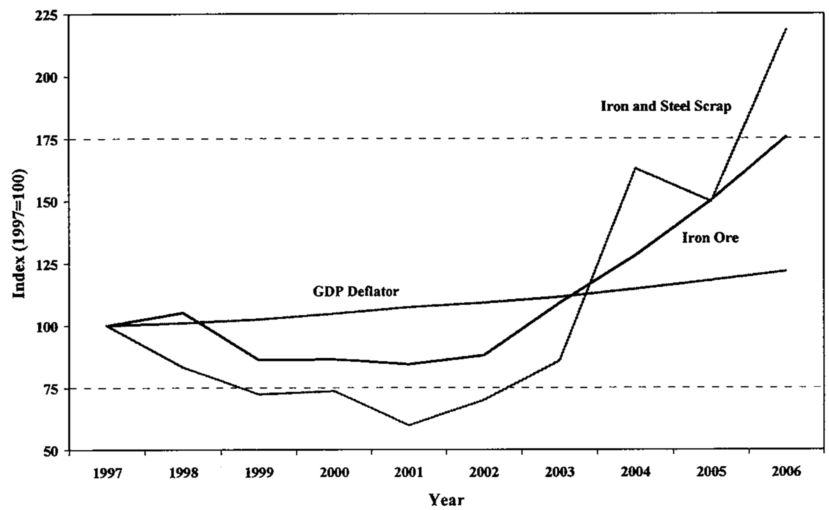
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar.

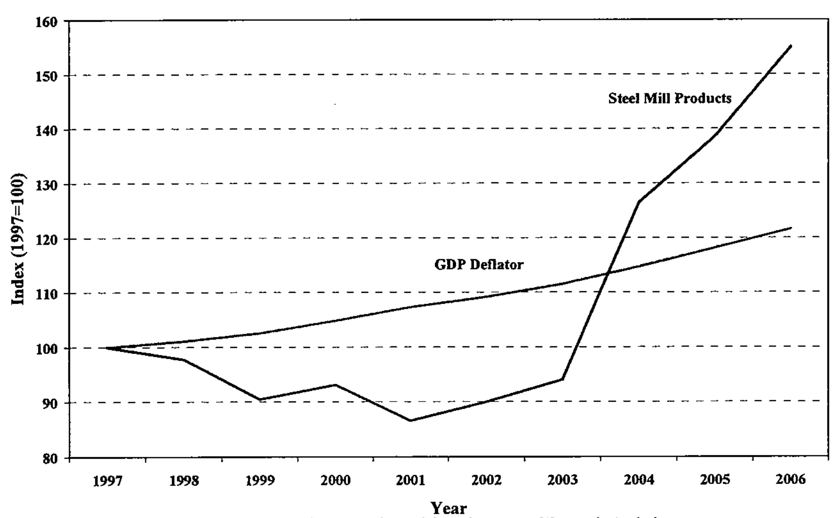
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



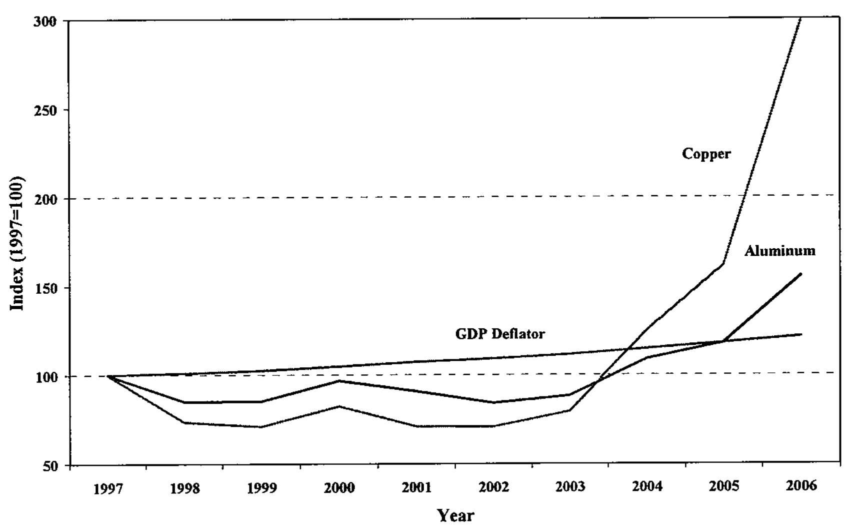
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

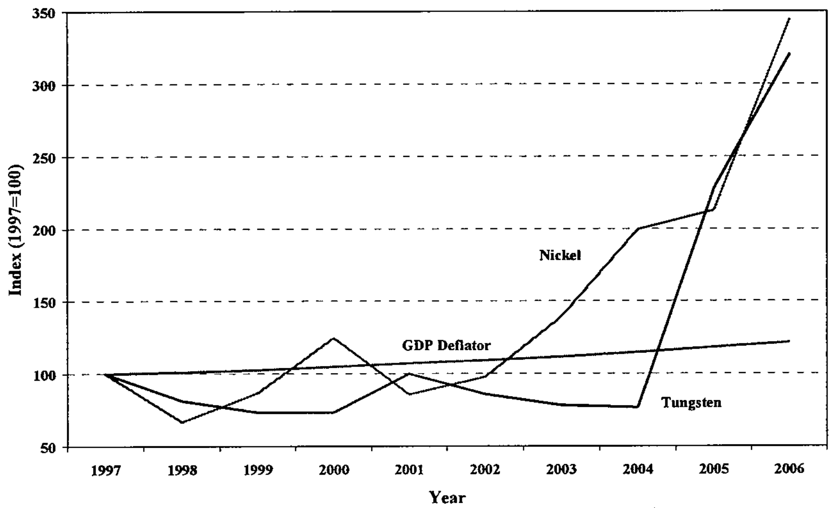


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

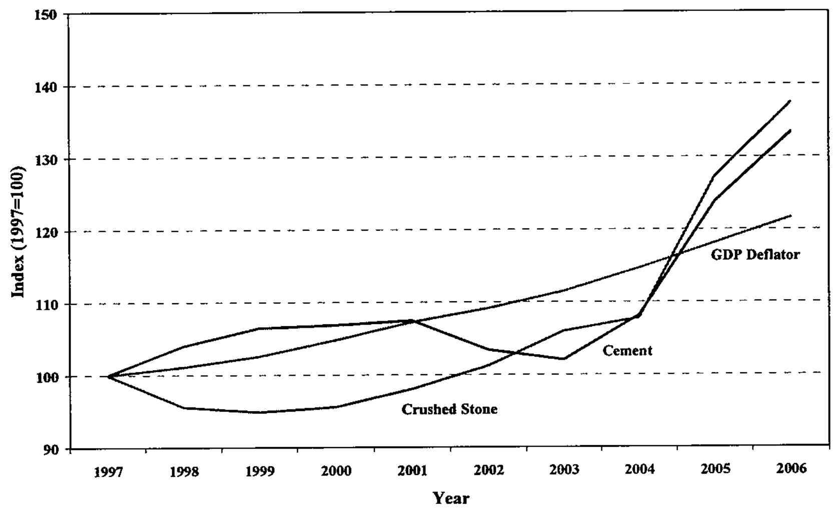


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

Figure 9
Cement and Crushed Stone Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

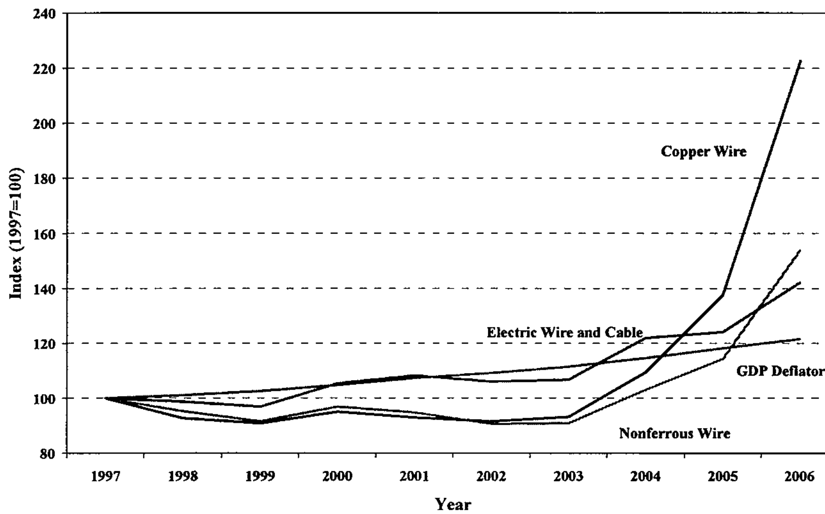
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

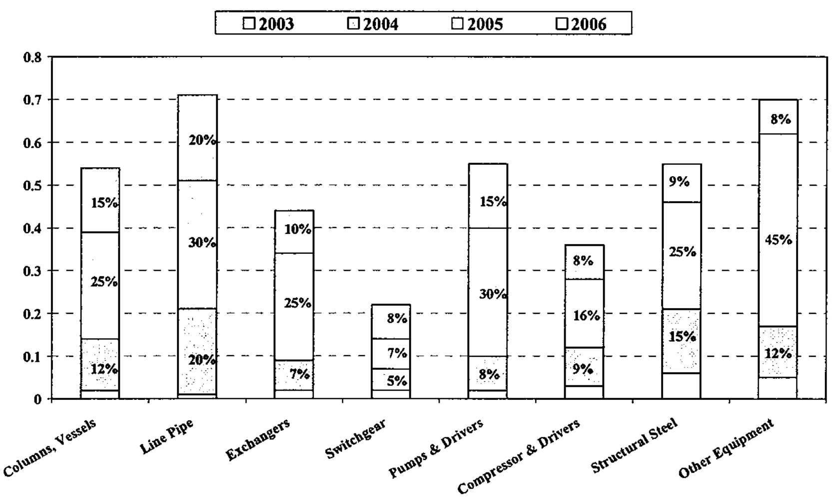
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

Figure 11
Equipment Price Increases

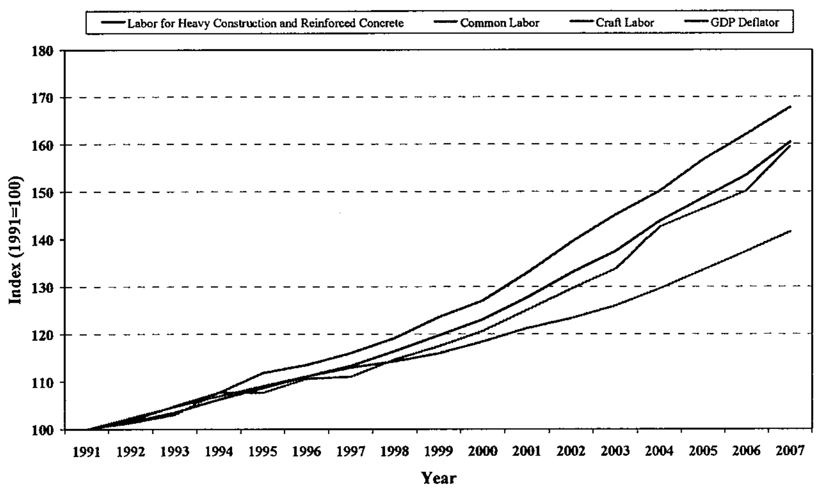


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage*. The Construction Users Roundtable, WP-401, June 2004, p. 1.

industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called "allowance for fund used during construction" (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

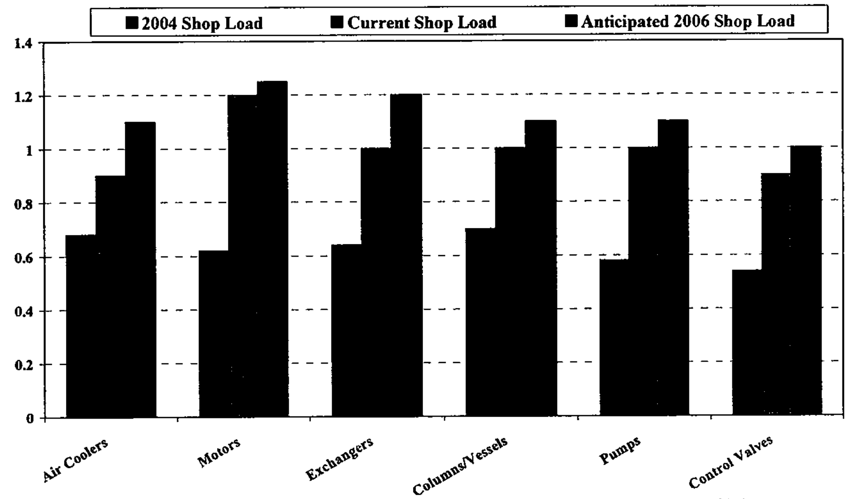
---

[14] *Id.*, p. 1.

[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005.* U.S. Department of Energy, August 2006, p. xi.

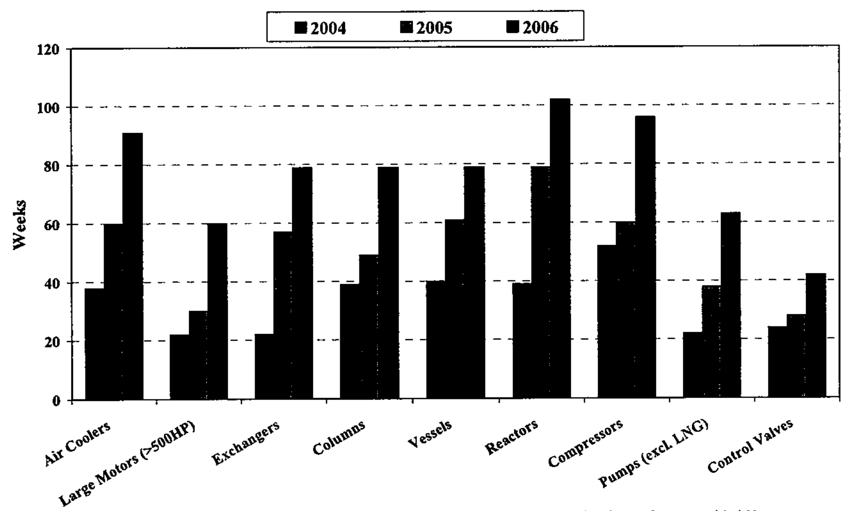
[16] *Id.*, p. 5.

Figure 13
Shop Capacity



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules

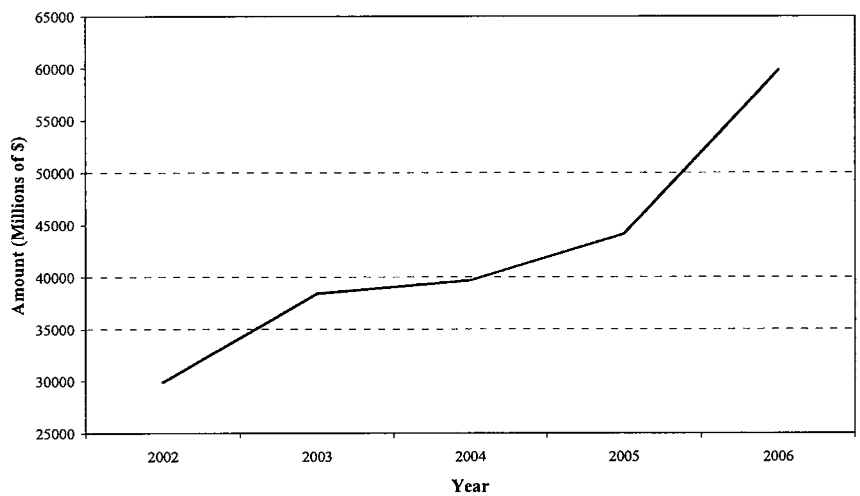


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints, combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

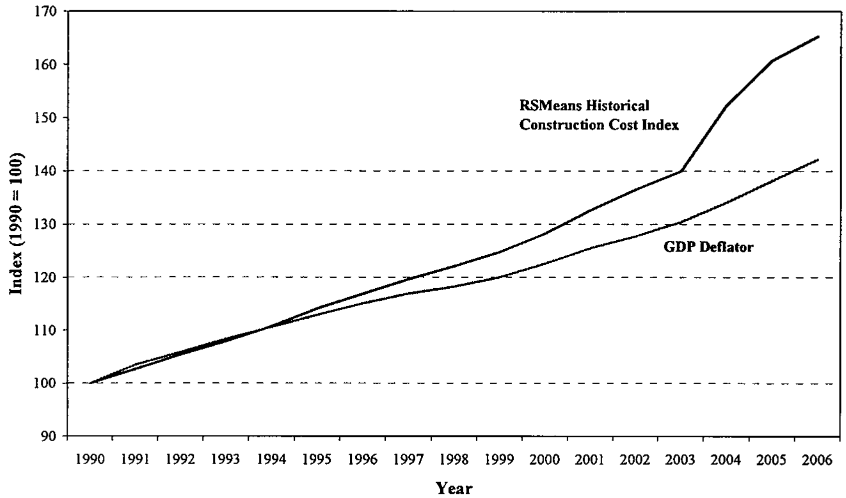
Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

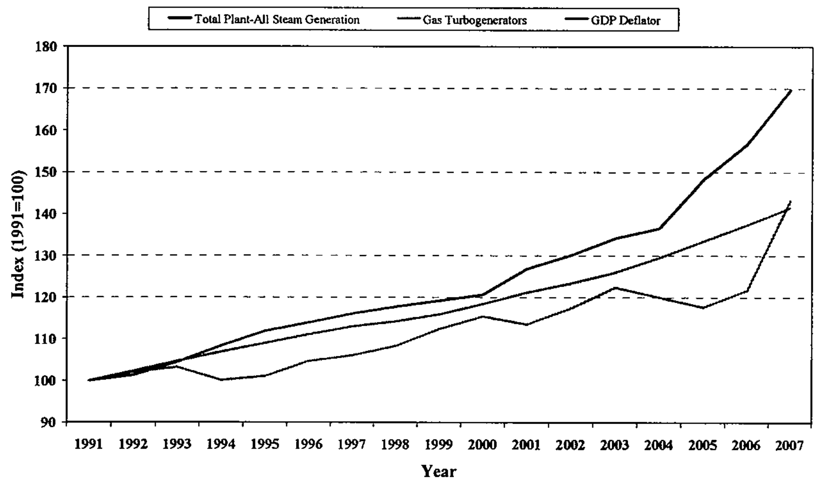
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

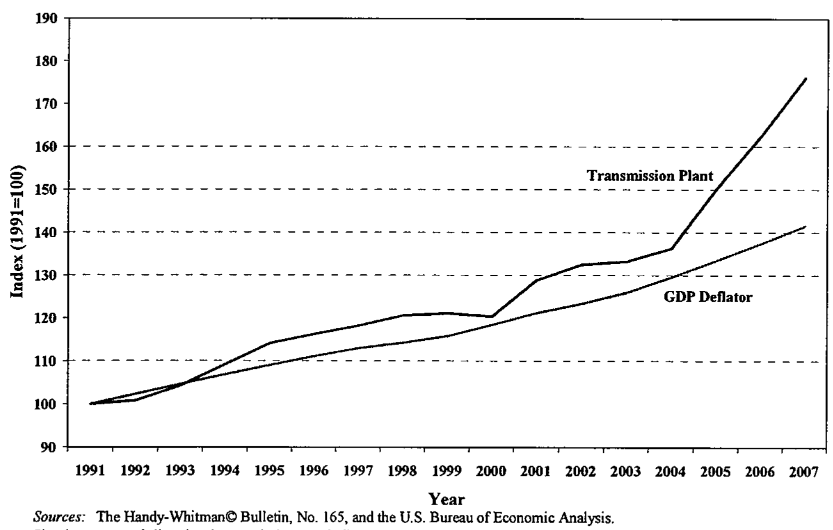
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components.

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

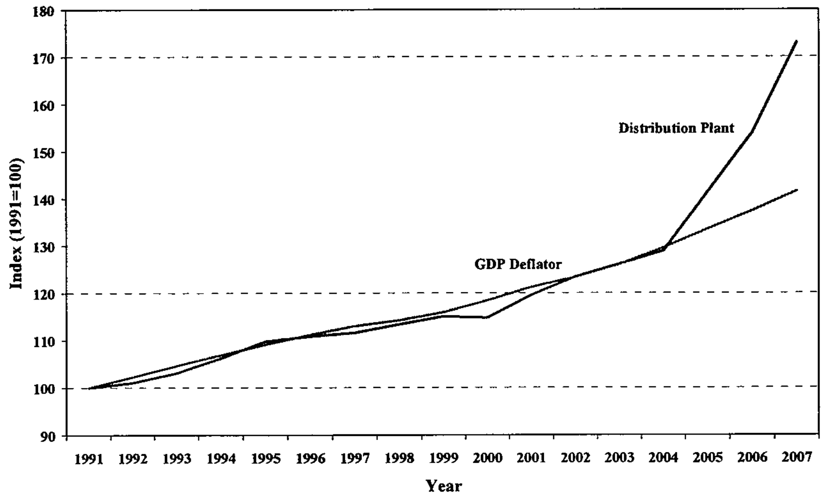
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices.

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g.*, fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units *(i.e.,* the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

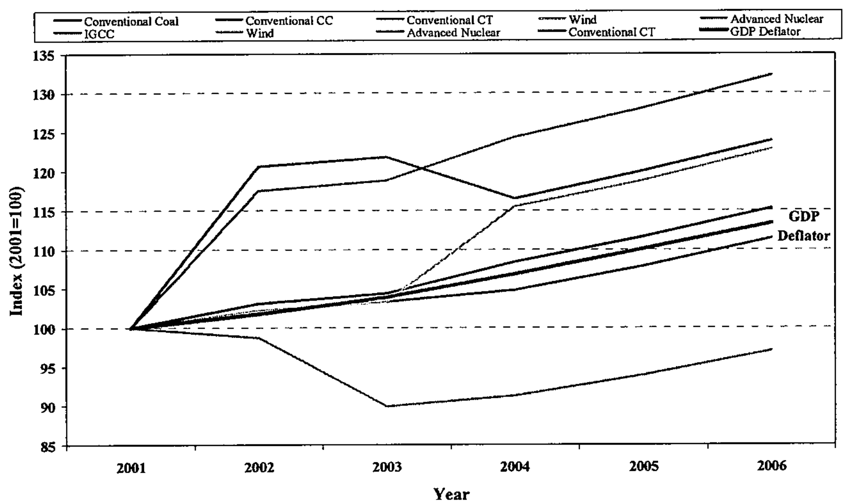
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

Conclusion

Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

chron.com | News, search and shopping from the HOUSTON CHRONICLE

Business

Feb. 13, 2008, 7:34PM

Power plant costs soar, hampering projects, report to say

But capacity is still expected to rise sharply, report says

By TOM FOWLER

The cost of building power plants in the U.S. has risen 76 percent in the last three years but 80 to 110 gigawatts of new generation capacity still will come online by 2012, according to a report set for release today.

A surge in construction activity globally, particularly for nuclear plants, is mainly driving the cost increase, said Candida Scott, who helped develop the Power Capital Costs Index that will be released by Cambridge Energy Research Associates today.

Since 2000 power plant costs have increased 130 percent, meaning a $1 billion project in 2000 would, on average, cost $2.3 billion today.

"None of us really saw the cost increases coming like this," Scott said. "Can it still continue to increase? Yes it can."

The CERA index deals with construction costs and didn't calculate how those would be passed along to consumers, but the report noted that plant construction costs eventually affect how much customers pay for the electricity.

In recent years the U.S. worked its way through a glut of power plants that were built in the late 1990s. Many projects have since been launched, including plans for more than a dozen new nuclear reactors.

The cost increases reflected in the index are part of the reason a number of U.S. coal plant projects have been canceled, Scott said, but growing public sentiment against the higher carbon dioxide emissions associated with the plants is also partly to blame.

The U.S. Department of Energy blamed rising project costs for its decision to pull out of commitments to fund FutureGen, a project that would have built a coal-fired power plant that captured and stored all of its CO_2 emissions underground.

The project was budgeted at around $950 million when first proposed but recent estimates put it at $1.8 billion.

"These costs are beginning to act as a drag on the power industry's ability to expand to meet growing demand, leading to delays and postponements," Scott said.

The index is based on a portfolio of fictional power projects that stretch across the U.S. and include all the different fuel types from coal to wind to nuclear.

CERA figured out the costs of design, labor, equipment, steel and concrete for the projects and added them to come up with a project cost as of the third quarter 2007.

Using historical cost data gathered through CERA partner PowerAdvocate, the company then recreated the fictional projects' costs going back to 2000.

The possibility of new legislation limiting carbon emissions in the U.S. has some impact on the costs tracked in the index, Scott said. But the index has not factored in higher project costs likely to follow the announcement earlier this month by a group of banks that they will consider future CO_2 legislative costs when lending to coal plant projects.

Nuclear plant costs account for about 52 percent of the price increases since 2000.

While orders for nuclear power-related equipment from U.S. companies are relatively new, European companies have continued to move forward with new projects over the years.

Scott said she expects the index will be used by project managers to help them explain costs to their superiors, but CERA is also planning to use it as a tool in its consulting practice.

tom.fowler@chron.com

MuchoGaseous wrote:
And the Building Bubble continues to grow. Refineries, petrochemical plants, Power plants, LNG gasification, etc. When it bursts, Look out .... Recession City.
2/14/2008 9:30 PM CST
Recommend Report abuse

high wrote:
Subject; Create a Houston Municipal Electricity Department

MISSION
The notion to create, a Houston Municipal Electricity Department has been generated by a ground roots group of citizens. After a detailed study was outlined and discussed among residents of civic organizations the decision was made to establish preface to Plan, Lead, Organize, and Control a business model to accommodate the citizens of Houston as a Retail Electric Provider (REP). The Houston Municipal Electricity Department would serve the public as defined by the Texas Public Utility Commission's designation of Retail Electric Provider under the 1999 deregulation Law. The purpose for establishing HMED it to assure the people of Houston the maximum economical value is obtained and verify the kWh price integrity.
A BUY and BILL Department
2/14/2008 5:55 PM CST
Recommend Report abuse

Texasgrandpa wrote:
I think we have the same problem here that we do with other costs to the consumer. Mr. Bush and others tied to the oil industry, will make their pockets fatter at any cost. The oil companies are the only group that has been exempt from any action by our cogress since Mr. Bush was elected. Now when the stimulus package is signed the oil companies see the opportunity to raise prices so they get the money instead of the people that need it. When any sign shows that the american public may get ahead and get releif, the oil traders see this as an opportunity to raise the price again.
2/14/2008 2:15 PM CST
Recommend Report abuse

bigoil wrote:
workorfish - Well.... I feel like most of them are told they are more important than what they really are. How hard is it to hire who I tell them to hire and "here sign these forms"?! I absolutely hate HR people! They are the ones who need to be contracted, not the working class people!
2/14/2008 8:54 AM CST
Recommend Report abuse

workorfish wrote:
bigoil, spot on with the company labor explanation. Why does it seem that HR folks are a bit sadistic?
2/14/2008 7:59 AM CST
Recommend Report abuse

Read all comments (10) ›

Attachment B

2.6 Incentives for New Generation Investment

Though California has seen significant levels of new generation investment over the past six years (2001-2006), investment in Southern California has not kept pace with unit retirements and load growth. Moreover, there is a continued reliance on very old and inefficient generation to meet Southern California reliability needs. Going forward, it is imperative that California has an adequate market/regulatory framework for facilitating new investment in the critical areas of the grid where it is needed, particularly Southern California. This section examines some of the issues that possibly affect incentives for new generation investment. It begins with an assessment of the extent to which spot market revenues in 2006 were sufficient to cover the annualized fixed cost of new generation. This is followed by an examination of the use of the must-offer obligation and Resource Adequacy contracts to meet reliability needs in 2006 and the potential impacts that this mechanism may have on incentives for long-term contracting. A review of the generation additions and retirements for 2001 through 2006 and projections for 2007 is provided at the end of this section, along with a review of the continued reliance on older generation facilities.

2.6.1 Revenue Adequacy for New Generation Investment

This section examines the extent to which the current spot markets operated by CAISO provide sufficient revenues to cover the annualized fixed costs of two types of generating units (combined cycle and combustion turbine). It is important to note that spot markets are inherently volatile and as such never guarantee fixed cost recovery, particularly if the market is over-supplied. Moreover, given the lead-time needed for new generation investment, current spot market prices may not be the best indicator for new investment. Expectations on future spot market prices – based on expectations of future supply and demand conditions – are likely to be a stronger driver for long-term contracting, which is the primary means for facilitating new investment. To the extent existing units are critical to meeting reliability needs, their annual fixed costs should be recoverable through a combination of long-term bilateral contracts and/or capacity markets and spot market revenues. Nonetheless, examining the extent to which current spot market prices alone can contribute to fixed cost recovery for new investment has proven to be an important market metric that all ISO's measure.

The annualized fixed costs used in this analysis are obtained from a California Energy Commission (CEC) report, which estimates the annualized fixed cost for a new combined cycle unit and a new combustion turbine to be $90/kW-year and $78/kW-year, respectively. The specific operating characteristics of the two unit types that these cost estimates are based on are provided in Table 2.9 and Table 2.10. It should be noted that the finance costs shown in these tables do include a rate of return on capital for equity investment.

Table 2.9 Analysis Assumptions: Typical New Combined Cycle Unit

Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Ramp Rate	5 MW
Heat Rates (MMBtu/kWh)	
Maximum Capacity	7,100
Minimum Operating Level	8,200
Financing Costs	$75 /kW-yr
Fixed Annual O&M	$15 /kW-yr
Other Variable O&M	$2.4/MWh
Startup Costs	
Gas Consumption	1,850 MMBtu/start
Fixed Cost Revenue Requirement	**$90/kW-yr**

Table 2.10 Analysis Assumptions: Typical New Combustion Turbine Unit

Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financing Costs	$58 /kW-yr
Fixed Annual O&M	$20 /kW/year
Other Variable O&M	$10.9/MWh
Startup Costs	
Gas Consumption	180 MMBtu
Fixed Cost Revenue Requirement	**$78/kW-yr**

2.6.2 Methodology

To provide a longer-term perspective, the net revenue analysis provided in this year's Annual Report was conducted over a 4-year period (2003-2006). Some improvements were made to the net revenue analysis methodology used in the 2005 Annual Report to provide a better estimate of potential spot market revenues. For consistency, these modifications were applied over the 4-year study period. Consequently, the numbers shown in this report may differ from those shown in the 2005 Annual Report, though the fundamental findings are the same.

The methodology used this year to calculate the net revenues earned by the hypothetical combined cycle described in Table 2.9 is based on the generator's participation in all possible markets: the Real Time Market and Ancillary Services Market operated by CAISO and the day-ahead bilateral energy markets. The specific methods used for the approach are described below.

Combined Cycle – Net Revenue Methodology

The operational and scheduling assumptions used to assess the potential revenues that could be earned by a typical new combined cycle unit are summarized below:

1) An initial operating schedule for day-ahead bilateral energy markets was determined based on the hourly spot market price index published by Powerdex and the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.9. The unit was scheduled up to full output when hourly prices exceed variable operating costs subject to observing the ramping limitations.

2) The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when day-ahead prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and restarting the unit; if operating losses exceeded these shutdown/startup costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded day-ahead bilateral energy prices.

3) If the unit was scheduled to stay off-line in the Day Ahead Market, it may be turned on in the Real Time Market operated by CAISO. The scheduling logic was the same as in the Day Ahead Market except that the Real Time Market clearing prices in both NP15 and SP15 were used instead of the Powerdex prices. The unit was scheduled up to full output when hourly real-time prices exceeded variable operating costs while observing the ramping limits.

4) Ancillary Service revenues were calculated by assuming the unit could provide up to 50 MW of spinning reserve each hour if it was committed in either the Day Ahead Market or Real Time Market for the hour and the output was smaller than its max stable level. The spinning reserve service prices were based on actual CAISO Day Ahead Market prices.

5) All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

6) Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues by 5 percent.

In last year's analysis, the results for SP15 also included possible Minimum Load Cost Compensation (MLCC) payments. The hours when the generator was committed under must-offer waiver denials were obtained from 2002 data. A more recent empirical study shows that the must-offer waiver denial hours for combined cycle units have reduced dramatically in the last three years.[15] Moreover, when combined cycle units were denied waivers, it was typically due to specific local and zonal reliability reasons and most qualified units were very old. Since our study was focused on incentive for new generation and only revenues from normal competitive market conditions were considered, such uplifts were not included in this year's analysis.

Combustion Turbine – Net Revenue Methodology

The methodology used this year to calculate the net revenues earned by the hypothetical combustion turbine unit described in Table 2.10 was the same as that of last year. It was based on market participation limited to the Real Time Market[16] and Ancillary Services Market. The specific methods used for these approaches are described below.

1) For each hour, it was assumed the unit would operate if the average hourly real-time price exceeded the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.10. The unit was scheduled up to full output when Real Time Market hourly prices exceeded variable operating costs while observing the ramping limits.

2) The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when Real Time Market prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and restarting the unit; if operating losses exceeded these shutdown/startup costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded real-time energy prices.

3) Ancillary service revenues were calculated by assuming the unit could provide up to 80 MW of non-spinning reserve each hour if it was committed during the hour. The non-spinning service prices were based on actual CAISO Day Ahead Market prices.

4) All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

5) Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues from real-time energy and non-spinning reserve sales by 5 percent.

[15] For 2003-2006 period, the total must-offer waiver denial hours for the combined cycle units in the CAISO Control Area ranged from 100 to 300.

[16] Real Time Market prices were used for the Combustion Turbine revenue analysis because this is a more likely market for fast-start units. However, the fact that the CAISO Real Time Market prices were often below prevailing day-ahead and day-of spot market prices, particularly during peak summer periods, makes the use of Real Time Market prices a somewhat conservative measure of potential energy market revenues.

2.6.3 Results

As noted in the previous methodology section, given the often significant differences between day-ahead bilateral prices and the CAISO real-time energy prices, particularly when the CAISO is decrementing resources in real-time, this year's revenue analysis includes additional analysis that examines potential net revenues for a hypothetical combined cycle unit if it participated in both energy markets. The above methodologies also assume that the unit could be dispatched based on perfect foresight of market prices in all participated markets, which is not possible in practice. Therefore, the results may overestimate the net revenues and thus, may be considered the upper limits of potential revenues.

The results for a combined cycle unit are summarized in Table 2.11. It shows a relatively increasing trend in the net revenues from 2004 to 2006. The total capacity factor remains relatively constant throughout the evaluation periods while the revenues from the Day Ahead Market increased in recent years, mainly due to higher prices in the short-term bilateral market. However, the estimated net revenues in all years are below the $90/kW-yr annualized cost of the unit – though the estimated net revenues for the SP15 2006 scenario came very close to the $90/kW-yr.

Table 2.12 shows the estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the CAISO Real Time Market as well as Ancillary Services Market. It shows a relatively stable trend in the net revenues from all years in the study period. Similar to the combined cycle analysis, the estimated revenues for a hypothetical combustion turbine unit fell well short of the $78/kW-yr annualized costs for all years (2003-2006) under all scenarios.

Table 2.11 Financial Analysis of New Combined Cycle Unit (2003–2006)

Components	2003		2004		2005		2006	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	66%	72%	69%	72%	65%	72%	63%	75%
DA Energy Revenue ($/kW - yr)	$233.90	$246.20	$274.80	$272.80	$372.40	$386.30	$319.70	$355.30
RT Energy Revenue ($/kW - yr)	$64.30	$73.20	$48.80	$56.10	$51.30	$63.80	$34.40	$50.00
A/S Revenue ($/kW – yr)	$0.80	$1.10	$0.70	$0.90	$1.40	$1.80	$1.00	$1.10
Operating Cost ($/kW - yr)	$245.10	$258.60	$276.70	$278.50	$363.10	$382.80	$279.50	$321.60
Net Revenue ($/kW – yr)	$53.90	$61.90	$47.60	$51.40	$62.00	$69.10	$75.50	$84.80
4-yr Average ($/kW – yr)	*$59.80*	*$66.80*						

Table 2.12 Financial Analysis of New Combustion Turbine Unit (2003-2006)

Components	2003		2004		2005		2006	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	15%	19%	9%	14%	8%	10%	7%	10%
Energy Revenue ($/kW - yr)	$118.10	$142.40	$72.80	$121.70	$87.50	$107.50	$69.50	$99.80
A/S Revenue ($/kW - yr)	$19.60	$18.20	$14.10	$27.40	$19.30	$18.50	$22.70	$21.70
Operating Cost ($/kW - yr)	$87.30	$108.00	$54.00	$81.60	$63.70	$82.00	$46.00	$68.90
Net Revenue ($/kW - yr)	$50.40	$52.70	$32.80	$67.50	$43.10	$44.10	$46.10	$52.40
4-yr Average ($/kW - yr)	*$43.10*	*$54.20*						

2.6.4 Discussion

The results shown in Table 2.11 and Table 2.12 indicate that net revenues appear to be sufficient to cover a unit's fixed operating and maintenance (O&M) costs on an annual basis. These fixed O&M costs are the fixed costs that a unit owner would be able to avoid incurring if the unit were not operated for the entire year (i.e., mothballed). Note that variable (fuel) costs (including start-up costs) are automatically covered since the simulation nets these costs against revenues to calculate net revenue. Fixed O&M costs, as reported by the CEC, are $15/kW-year for a combined cycle unit and $20/kW-year for a combustion turbine unit. If net revenues are expected to exceed fixed O&M costs, it should be sufficient to keep an existing unit operating from year to year. However, in order to provide an incentive for new generation investment, expected net revenues over a multi-year timeframe would need to exceed the total fixed costs of a unit (e.g., $90/KW-year for a combined cycle unit).

The results above show that total fixed cost recovery, fixed O&M cost plus the cost of capital, was not achieved for either generation technology in any of the four years. In the case of the combustion turbine unit, net revenues were generally well below the total fixed cost estimate of $78/kW-year. The four year average net revenues ranged from $33/kW-yr to $50/kW-yr in the NP15 area and $44/kW-yr to $68/kW-yr in the SP15 area. The four year averages were $43/kW-yr in the NP15 area and $54/kW-yr in the SP15 area. However, as previously noted, basing potential energy market revenues solely on CAISO Real Time Market prices may tend to understate potential revenues given that real-time prices are generally below the day-ahead and day-of market prices. The same result is true for combined cycle units, where the total fixed cost of $90/KW-year is never fully reached, even when all potential revenues are accounted for. However, revenue analysis for combined cycle units does reveal a favorable trend over the past three years (2004-2006) with estimated net revenues increasing in both zones over this period. The increase for 2006 is mainly due to higher short-term bilateral market prices. The annual net revenues ranged from $48/kW-yr to $76/kW-yr in the NP15 area and $61/kW-yr to $85/kW-yr in the SP15 area. The four year averages were $60/kW-yr in the NP15 area and $67/kW-yr in the SP15 area.

Given the need for new generation investment in California, the finding that estimated spot market revenues failed to provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2006) but the net revenue earned in 2006 is not indicative of future market revenue opportunities, which is the primary driver for new investment. In any case, future market design features that could provide better price signals and revenue opportunities for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation on February 1, 2008, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) should also be seriously considered for future adoption.

In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and similar programs for non-CPUC jurisdictional entities. These programs can provide additional revenue for new generation and cover the gap between annualized capital cost and simulated net spot market revenues provided in the previous section.

While a broader range of contracting opportunities are being developed that could provide additional incentives for new generation, the continued reliance on an aging pool of generating

Attachment C

Attachment C

Combustion Turbine (CT) Fixed Costs -- Use 2007 CT Capital Costs

INITIAL INVESTMENT ($/kW)	$ 1,255	(average of SCE and CEC 2007 CT Costs)		
REAL FIXED CHARGE RATE	9.94%			

Year	Real Fixed Charge $/kW	Insurance Cost 0.25% $/kW	Fixed O&M $/kW	Total CT Marginal Cost $/kW
(Column Number from Table B-2 of TURN's August 31, 2005 Testimony) =>	*15*	*16*	*17*	*18*
2007	124.75	3.14	8.45	136.33
2008	127.87	3.22	8.71	139.79
2009	131.06	3.30	8.97	143.33
2010	134.34	3.38	9.25	146.97
2011	137.70	3.46	9.53	150.69
2012	141.14	3.55	9.82	154.51
2013	144.67	3.64	10.11	158.42
2014	148.28	3.73	10.42	162.43
2015	151.99	3.82	10.73	166.54
2016	155.79	3.92	11.05	170.76
2017	159.69	4.02	11.37	175.07
2018	163.68	4.12	11.71	179.51
2019	167.77	4.22	12.05	184.04
2020	171.97	4.33	12.40	188.69
2021	176.26	4.43	12.76	193.46
2022	180.67	4.54	13.13	198.34
2023	185.19	4.66	13.51	203.36
2024	189.82	4.77	13.89	208.48
2025	194.56	4.89	14.29	213.75
2026	199.43	5.02	14.70	219.14
2027	204.41	5.14	15.12	224.67
2028	209.52	5.27	15.54	230.33
2029	214.76	5.40	15.97	236.13
2030	220.13	5.54	16.42	242.08
2031	225.63	5.67	16.87	248.18
NPV	$1,568.19	$39.44	$110.93	$1,718.56
Levelized Nominal	153.85	3.87	10.88	168.60

2008 CT Fixed Costs Net of Energy Rents and Ancillary Service Revenues

First-Year Cost of Capacity (2008)	139.79	$/kW-year
Energy Rents and Ancillary Services	48.65	$/kW-year
Net Capacity Cost	91.14	$/kW-year

Attachment D

Attachment D

Combined Cycle Gas Turbine (CCGT) Fixed Costs

2007 MPR (from Resolution E-4118)		
(Assumes 2008 start-date and a 10-year contract)		
Fixed-price Component	27.20	$/MWh
Capacity Factor	76%	
Fixed-price Component	**181.12**	$/kW-year
Energy Market Rents ($/kW-year)	**(62.20)**	$/kW-year
(CAISO 2006 Annual Report average for 2003 to 2006)		
Out-year value (after year 20)	**(10.00)**	$/kW-year
Net Fixed Cost	**108.92**	$/kW-year

Certificate of Service

I hereby certify that I have this day served a copy of the

Petition of the California Cogeneration Council for Modification of Decision 07-09-040

on all known parties to R.04-04-003 and R.04-04-025 by sending a copy via electronic mail and by mailing a properly addressed copy by first-class mail with postage prepaid to each party named in the official service list without an electronic mail address.

Executed on March 3, 2008 at San Francisco, California.

Rosalie Marschall

Rosalie Marschall

Service List for R.04-04-003
Last Changed February 28, 2008

anogee@ucsusa.org
roger@berlinerlawpllc.com
Cynthia.A.Fonner@constellation.com
jimross@r-c-s-inc.com
toms@i-cpg.com
todil@mckennalong.com
maureen@lennonassociates.com
douglass@energyattorney.com
berj.parseghian@sce.com
woodrujb@sce.com
janet.combs@sce.com
michael.backstrom@sce.com
daking@sempra.com
gbaker@sempra.com
cneedham@edisonmission.com
phil@reesechambers.com
mflorio@turn.org
cwl@cpuc.ca.gov
kpp@cpuc.ca.gov
map@cpuc.ca.gov
dwang@nrdc.org
ek@a-klaw.com
evk1@pge.com
magq@pge.com
saw0@pge.com
agrimaldi@mckennalong.com
kbowen@winston.com
jkarp@winston.com
jeffgray@dwt.com
alhj@pge.com
ssmyers@att.net
rick_noger@praxair.com
wbooth@booth-law.com
hoerner@redefiningprogress.org
cchen@ucsusa.org
elarsen@rcmdigesters.com
gmorris@emf.net
nrader@calwea.org
tomb@crossborderenergy.com
pcmcdonnell@earthlink.net
wem@igc.org
michaelboyd@sbcglobal.net
joyw@mid.org
brbarkovich@earthlink.net
bill@jbsenergy.com.
Dick@DavisHydro.com
grosenblum@caiso.com
sford@caiso.com
abb@eslawfirm.com
dkk@eslawfirm.com
atrowbridge@daycartermurphy.com
mpa@a-klaw.com
carlo.zorzoli@enel.it
dgulino@ridgewoodpower.com
bshort@ridgewoodpower.com
sesco@optonline.net
csmoots@perkinscoie.com
myuffee@mwe.com
rshapiro@chadbourne.com
ralph.dennis@constellation.com
dmcfarlan@mwgen.com
brianhaney@useconsulting.com
dsaul@pacificsolar.net
chilen@sppc.com
rprince@semprautilities.com
hchoy@isd.co.la.ca.us
dhuard@manatt.com
pucservice@manatt.com
curtis.kebler@gs.com
sam@climateregistry.org
mgibbs@icfconsulting.com
Case.Admin@sce.com
j.eric.isken@sce.com
gary.allen@sce.com
laura.genao@sce.com
lizbeth.mcdannel@sce.com
tory.weber@sce.com
jyamagata@semprautilities.com
dwood8@cox.net
tim.hemig@nrgenergy.com
kmelville@sempra.com
gbass@semprasolutions.com
liddell@energyattorney.com
scottanders@sandiego.edu
bpowers@powersengineering.com
centralfiles@semprautilities.com
cmanzuk@semprautilities.com
irene.stillings@energycenter.org
jkloberdanz@semprautilities.com
dpapapostolou@semprautilities.com
jleslie@luce.com
lkostrzewa@edisonmission.com
pherrington@edisonmission.com
bjl@bry.com
pepper@cleanpowermarkets.com
chris@emeter.com
mdjoseph@adamsbroadwell.com
slefton@aptecheng.com
diane_fellman@fpl.com
freedman@turn.org

Service List for R.04-04-003
Last Changed February 28, 2008

nao@cpuc.ca.gov
norman.furuta@navy.mil
filings@a-klaw.com
nes@a-klaw.com
rsa@a-klaw.com
ell5@pge.com
mekd@pge.com
mrh2@pge.com
cem@newsdata.com
bcragg@goodinmacbride.com
jscancarelli@flk.com
koconnor@winston.com
lcottle@winston.com
ren@ethree.com
ldolqueist@manatt.com
bobgex@dwt.com
stevegreenwald@dwt.com
CRMd@pge.com
cpuccases@pge.com
mdbk@pge.com
ecrem@ix.netcom.com
l_brown369@yahoo.com
mecsoft@pacbell.net
GXL2@pge.com
karp@pge.com
vjw3@pge.com
k.abreu@sbcglobal.net
mark_j_smith@fpl.com
beth@beth411.com
mhharrer@sbcglobal.net
andy.vanhorn@vhcenergy.com
alexm@calpine.com
kowalewskia@calpine.com
duggank@calpine.com
sbeserra@sbcglobal.net
phanschen@mofo.com
editorial@californiaenergycircuit.net
mrw@mrwassoc.com
mrw@mrwassoc.com
mrw@mrwassoc.com
rschmidt@bartlewells.com
janice@strategenconsulting.com
tomk@mid.org
sarveybob@aol.com
gabriellilaw@sbcglobal.net
rmccann@umich.edu
demorse@omsoft.com
davidreynolds@ncpa.com
steveng@destrategies.com
dougdpucmail@yahoo.com
dcarroll@downeybrand.com
etiedemann@kmtg.com
kdw@woodruff-expert-services.com
steven@iepa.com
www@eslawfirm.com
vwood@smud.org
rlauckhart@henwoodenergy.com
jesus.arredondo@nrgenergy.com
karen@klindh.com
pholley@covantaenergy.com
rfp@eesconsulting.com
dws@r-c-s-inc.com
ppl@cpuc.ca.gov
ayk@cpuc.ca.gov
cab@cpuc.ca.gov
chh@cpuc.ca.gov
djh@cpuc.ca.gov
joh@cpuc.ca.gov
jmh@cpuc.ca.gov
msw@cpuc.ca.gov
mjd@cpuc.ca.gov
mts@cpuc.ca.gov
mkh@cpuc.ca.gov
gig@cpuc.ca.gov
rls@cpuc.ca.gov
skh@cpuc.ca.gov
car@cpuc.ca.gov
skg@cpuc.ca.gov
tdp@cpuc.ca.gov
tcx@cpuc.ca.gov
tcr@cpuc.ca.gov
tbo@cpuc.ca.gov
bmeister@energy.state.ca.us
dks@cpuc.ca.gov
kris.chisholm@eob.ca.gov
mjaske@energy.state.ca.us
wsm@cpuc.ca.gov
ikwasny@water.ca.gov
mmiller@energy.state.ca.us
rwethera@energy.state.ca.us

Service List for R.04-04-003
Last Changed February 28, 2008

Via U.S.Mail:

Anan H. Sokker
Chadbourne & Parke LLP
1200 New Hampshire Ave., NW
Washington, DC 20005

Tandy McMannes
Solar Thermal Electric Alliance
101 Ocean Bluffs Blvd.
Apt. 504
Jupiter, FL 33477

Shawn Smallwood, PhD
109 Luz Place
Davis, CA 95616

Williams Power Company
3161 Ken Derek Lane
Placerville, CA 95616

Snuller Price
Energy and Environmental Economics
101 Montgomery St.
Ste 1600
San Francisco, CA 94104

Via Hand Delivery

President Michael R. Peevey
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

E-Service List for R.04-04-025
Last Changed February 28, 2008

anogee@ucsusa.org
roger@berlinerlawpllc.com
Cynthia.A.Fonner@constellation.com
jimross@r-c-s-inc.com
toms@i-cpg.com
todil@mckennalong.com
maureen@lennonassociates.com
douglass@energyattorney.com
berj.parseghian@sce.com
woodrujb@sce.com
janet.combs@sce.com
michael.backstrom@sce.com
daking@sempra.com
gbaker@sempra.com
cneedham@edisonmission.com
phil@reesechambers.com
mflorio@turn.org
cwl@cpuc.ca.gov
kpp@cpuc.ca.gov
map@cpuc.ca.gov
dwang@nrdc.org
ek@a-klaw.com
evk1@pge.com
magq@pge.com
saw0@pge.com
agrimaldi@mckennalong.com
kbowen@winston.com
jkarp@winston.com
jeffgray@dwt.com
alhj@pge.com
ssmyers@att.net
rick_noger@praxair.com
wbooth@booth-law.com
hoerner@redefiningprogress.org
cchen@ucsusa.org
elarsen@rcmdigesters.com
gmorris@emf.net
nrader@calwea.org
tomb@crossborderenergy.com
pcmcdonnell@earthlink.net
wem@igc.org
michaelboyd@sbcglobal.net
joyw@mid.org
brbarkovich@earthlink.net
bill@jbsenergy.com.
Dick@DavisHydro.com
grosenblum@caiso.com
sford@caiso.com
abb@eslawfirm.com
dkk@eslawfirm.com
atrowbridge@daycartermurphy.com
mpa@a-klaw.com
carlo.zorzoli@enel.it
dgulino@ridgewoodpower.com
bshort@ridgewoodpower.com
sesco@optonline.net
csmoots@perkinscoie.com
myuffee@mwe.com
rshapiro@chadbourne.com
ralph.dennis@constellation.com
dmcfarlan@mwgen.com
brianhaney@useconsulting.com
dsaul@pacificsolar.net
chilen@sppc.com
rprince@semprautilities.com
hchoy@isd.co.la.ca.us
dhuard@manatt.com
pucservice@manatt.com
curtis.kebler@gs.com
sam@climateregistry.org
mgibbs@icfconsulting.com
Case.Admin@sce.com
j.eric.isken@sce.com
gary.allen@sce.com
laura.genao@sce.com
lizbeth.mcdannel@sce.com
tory.weber@sce.com
jyamagata@semprautilities.com
dwood8@cox.net
tim.hemig@nrgenergy.com
kmelville@sempra.com
gbass@semprasolutions.com
liddell@energyattorney.com
scottanders@sandiego.edu
bpowers@powersengineering.com
centralfiles@semprautilities.com
cmanzuk@semprautilities.com
irene.stillings@energycenter.org
jkloberdanz@semprautilities.com
dpapapostolou@semprautilities.com
jleslie@luce.com
lkostrzewa@edisonmission.com
pherrington@edisonmission.com
bjl@bry.com
pepper@cleanpowermarkets.com
chris@emeter.com
mdjoseph@adamsbroadwell.com
slefton@aptecheng.com
diane_fellman@fpl.com
freedman@turn.org

E-Service List for R.04-04-025
Last Changed February 28, 2008

nao@cpuc.ca.gov
norman.furuta@navy.mil
filings@a-klaw.com
nes@a-klaw.com
rsa@a-klaw.com
ell5@pge.com
mekd@pge.com
mrh2@pge.com
cem@newsdata.com
bcragg@goodinmacbride.com
jscancarelli@flk.com
koconnor@winston.com
lcottle@winston.com
ren@ethree.com
ldolqueist@manatt.com
bobgex@dwt.com
stevegreenwald@dwt.com
CRMd@pge.com
cpuccases@pge.com
mdbk@pge.com
ecrem@ix.netcom.com
l_brown369@yahoo.com
mecsoft@pacbell.net
GXL2@pge.com
karp@pge.com
vjw3@pge.com
k.abreu@sbcglobal.net
mark_j_smith@fpl.com
beth@beth411.com
mhharrer@sbcglobal.net
andy.vanhorn@vhcenergy.com
alexm@calpine.com
kowalewskia@calpine.com
duggank@calpine.com
sbeserra@sbcglobal.net
phanschen@mofo.com
editorial@californiaenergycircuit.net
mrw@mrwassoc.com
mrw@mrwassoc.com
mrw@mrwassoc.com
rschmidt@bartlewells.com
janice@strategenconsulting.com
tomk@mid.org
sarveybob@aol.com
gabriellilaw@sbcglobal.net
rmccann@umich.edu
demorse@omsoft.com
davidreynolds@ncpa.com
steveng@destrategies.com
dougdpucmail@yahoo.com
dcarroll@downeybrand.com
etiedemann@kmtg.com
kdw@woodruff-expert-services.com
steven@iepa.com
www@eslawfirm.com
vwood@smud.org
rlauckhart@henwoodenergy.com
jesus.arredondo@nrgenergy.com
karen@klindh.com
pholley@covantaenergy.com
rfp@eesconsulting.com
dws@r-c-s-inc.com
ppl@cpuc.ca.gov
ayk@cpuc.ca.gov
cab@cpuc.ca.gov
chh@cpuc.ca.gov
djh@cpuc.ca.gov
joh@cpuc.ca.gov
jmh@cpuc.ca.gov
msw@cpuc.ca.gov
mjd@cpuc.ca.gov
mts@cpuc.ca.gov
mkh@cpuc.ca.gov
gig@cpuc.ca.gov
rls@cpuc.ca.gov
skh@cpuc.ca.gov
car@cpuc.ca.gov
skg@cpuc.ca.gov
tdp@cpuc.ca.gov
tcx@cpuc.ca.gov
tcr@cpuc.ca.gov
tbo@cpuc.ca.gov
bmeister@energy.state.ca.us
dks@cpuc.ca.gov
kris.chisholm@eob.ca.gov
mjaske@energy.state.ca.us
wsm@cpuc.ca.gov
ikwasny@water.ca.gov
mmiller@energy.state.ca.us
rwethera@energy.state.ca.us

E-Service List for R.04-04-025
Last Changed February 28, 2008

Via U.S.Mail:

Anan H. Sokker
Chadbourne & Parke LLP
1200 New Hampshire Ave., NW
Washington, DC 20005

Tandy McMannes
Solar Thermal Electric Alliance
101 Ocean Bluff's Blvd.
Apt. 504
Jupiter, FL 33477

Shawn Smallwood, PhD
109 Luz Place
Davis, CA 95616

Williams Power Company
3161 Ken Derek Lane
Placerville, CA 95616

Snuller Price
Energy and Environmental Economics
101 Montgomery St.
Ste 1600
San Francisco, CA 94104

Via Hand Delivery

President Michael R. Peevey
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Amy Yip-Kikugawa
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102